

NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD

IN THE MATTER OF the *Public Utilities Act*, R.S.N.W.T. 1988, c. 24 (Supp.), as amended;

AND IN THE MATTER OF the *Northwest Territories Power Corporation Act*, R.S.N.W.T. 1988, c. N-2, as amended;

AND IN THE MATTER OF the Northwest Territories Public Utilities Board Decision 13-2007 dated August 29, 2007;

AND IN THE MATTER OF the Northwest Territories Power Corporation's 2006/07 and 2007/08 Phase I General Rate Application Refiling Pursuant to Decision 13-2007.

**PHASE I REILING REPLY ARGUMENT OF
THE NORTHWEST TERRITORIES POWER
CORPORATION**

October 30, 2007

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1. Introduction

The Northwest Territories Power Corporation (the “Corporation” or “NTPC”) has received written argument in this Refiling proceeding filed on behalf of:

- the City of Yellowknife and the Towns of Hay River and Fort Smith (collectively the “Hydro Communities” or “HC”) dated October 23, 2007 (the “HC Argument”); and
- the Town of Inuvik, Village of Fort Simpson and Hamlet of Fort Liard (collectively the “Thermal Generation Communities” or “TGC”) dated October 23, 2007 (the “TGC Argument”).

The Corporation also filed written argument in this Refiling proceeding dated October 23, 2007 (the “NTPC Argument”).

The Corporation has organized its Reply Argument with reference to the appropriate headings used in the arguments filed by the Corporation and those interveners. Terms and phrases defined in the NTPC Argument have the same meaning in this Reply Argument unless otherwise specified herein. To the extent that the Corporation does not expressly reply to an issue raised or position taken by the Hydro Communities or the Thermal Generation Communities, the Corporation has no position on that matter and should not be deemed to agree with or consent to the Intervener’s position.

2. Directive No. 2 – Aklavik Plant

The TGC submits that “...the 50% risk sharing adjustment should be calculated as being the difference between the AFUDC and Overhead amounts approved by the Board in Decision 11-2006 (of \$0.515 million) and the amount proposed for inclusion in rate base (\$0.823 million).”¹ The TGC’s submission is incorrect and should be denied for the following three reasons.

First, the amount of AFUDC and overheads proposed for inclusion in ratebase is \$0.878 million (\$0.457 million + \$0.421 million), not \$0.823 million as suggested by the TGC. Rather, \$0.823 million is the amount of AFUDC and overheads included the original budget estimate of \$4.3 million.²

Second, the basic issue raised by the TGC is what are the appropriate points of comparison to calculate the risk sharing adjustment? The Corporation addressed that issue in response to Refiling IRs TGC.NTPC-1(d) as follows:

As per Directive 2 from Decision 13-2007, Table 1 of the Phase 1 re-filing calculates the difference in AFUDC and overheads from the original project budget (\$4.3 million with AFUDC and overheads) to the capital addition in the 2006/08 GRA (\$5.3 million with AFUDC and overheads). *The comparison from original budget to the 2006/08 GRA application is the appropriate point of comparison as it addresses the Board’s concern over the additional costs in*

¹ TGC Argument at 3-4.

² Refiling, p. 4, ln. 20, Table 1.

1 *AFUDC and overheads from when the project was first planned.* This approach
 2 includes any inflationary impacts while NTPC undertook additional community
 3 consultation and temporary redeployed resources to address the emergency plant
 4 rebuild in Fort McPherson. [emphasis added]

5 Consequently, the appropriate risk sharing calculation, as set out in the Corporation's response to
 6 Directive No. 2, is 50% of the difference between the AFUDC and overhead amounts in the
 7 original budget estimate (\$0.823 million) and the amount proposed for inclusion in rate base
 8 (\$0.878 million).

9 Third, the Aklavik plant project was supported by the Hamlet of Aklavik ("Aklavik") after
 10 significant consultations about the various options and corresponding costs.³ The Corporation
 11 continues to consult with Aklavik regarding current plant addition costs and is not aware of any
 12 objections, nor has there been any objections made in this proceeding by Aklavik, which is a
 13 registered party.

14 The TGC also questions why the correction to forecast AFUDC for 2005/06 and 2006/07 noted
 15 by the Corporation in Refiling IRs TGC.NTPC-1(b&c) was not brought to the Board's attention
 16 earlier.⁴ The Corporation was not aware of that error until it was preparing its response to the
 17 Refiling IRs and brought the error to the Board's and parties attention at its first opportunity.
 18 Further, the error does not impact the appropriate risk sharing calculation discussed above. It is
 19 also notable that AFUDC is a very difficult expense to forecast for multiple year projects, as the
 20 actual total project AFUDC will depend upon the year-to-year timing of project costs and the
 21 outstanding liability at each year end.

22 **3. Directive Nos. 5 and 6 – Sinking Fund Earnings**

23 The HC take the position that:

24 ...to be consistent with the use of mid-year balances for long term debt and
 25 sinking fund balances, not to mention rate base, SFE [sinking fund earnings]
 26 should be calculated by applying the 6% average return to the mid-year balance of
 27 sinking funds. The HC have recalculated the SFE for the years 2006/07 and
 28 2007/08 using the 6% average return and the mid-year balance of sinking funds
 29 (line 11) with the result that the SFE on line 12, Schedule 3.7 Revised should be
 30 (2,430) in 2006/07 and (2,764) in 2007/08.⁵

³ Refiling IRs, TGC.NTPC-1(a); Aklavik Major Project Permit Application dated February 28, 2006, p. 4 of 8; Ex. 2, p. 6-49, lns. 6-14.

⁴ TGC Argument at 4.

⁵ HC Argument at 3. Regarding the use of mid-year balances for long term debt, the Board directed the Corporation to use mid-year debt values to determine the denominator in the average cost of debt calculation (Decision 13-2007 at 26-27). In all cases NTPC continued to use the actual interest paid or forecast to be paid during the year divided by this mid-year balance to determine the effective cost of long term debt. For all but one of NTPC's debt instruments, the interest expense is equal to the face interest times the mid-year balance. However, for the 6.42% amortizer, the interest expense reflects the interest paid or forecast to be paid during the year based on actual debt outstanding during the course of the year, which is not equal to simple mid-year balance. This is because the principal payment occurs in December, about three quarters of the way through the year. The difference between this treatment and the simple mid-year treatment on interest expense is very small

1 The Corporation disagrees with the HC's calculation for the following reasons.

2 First, as noted in Tables 4 through 10 of the Corporation's Response to HC.NTPC-23 and
 3 Undertaking #11 from the Technical Workshop, sinking fund earnings are reported net of
 4 management fees (\$140,000 in 2006/07 and \$143,000 in 2007/08).⁶ The HC's calculation fails
 5 to account for management fees. Sinking fund management fees are a prudent and necessary
 6 expense for the Corporation to incur. Alternatively, the Corporation could hire staff to provide
 7 those services with the corresponding incremental expense being reflected in its forecast salaries
 8 and wages. If the sinking fund management fees were not netted off the sinking fund earnings
 9 for calculating the effective cost of long-term debt, then the Corporation would be required to
 10 include those costs as part of its supplies and services expense in the test years.

11 Second, the HC bases their mid-year calculation on a closing sinking fund balance in each year
 12 that already includes interest earned during the year. The closing sinking fund balance reported
 13 at line 3 of Schedule 3.7 in the response to Refiling IRs HC.NTPC-1 is the sum of the opening
 14 balance, plus contributions in the year, plus interest earned during the year as shown in Table 1
 15 below. As a result, the HC's calculation of the 6% interest is significantly overstated.

16 **Table 1. Calculation of Sinking Fund Closing Balances (\$000)**

	<u>2006/07</u>	<u>2007/08</u>
1 Opening Balance	37,804	43,202
2 add: Contributions	3,043	3,043
3 add: Sinking Fund Earnings	2,354	2,677
4 Closing Balance	43,202	48,922

17
 18 Third, the HC contend that "[i]t is not clear how NTPC calculated the Sinking Fund Earnings in
 19 the test years based on long term average return of 6% (SFE)."⁷ The Corporation illustrated how
 20 it calculates sinking fund earnings in its response to HC.NTPC-23(k).⁸ It weights the earnings
 21 on the contribution in each year according to when it occurs in the year. For example, if the
 22 contribution is made at the end of the third quarter, the 6% applies only to the portion of the year
 23 after the contribution is made (i.e. the fourth quarter). That method has been applied by the
 24 Corporation throughout the Phase I and Refiling proceedings.

25 Fourth, it should be noted that Directive Nos. 5 and 6 did not require that the Corporation
 26 calculate the 6% sinking fund return on the simple mid-year average balance. Consequently, the
 27 Corporation applied the daily weighted average balance methodology consistent with the
 28 Application. Notwithstanding this, the Corporation agrees that sinking fund earnings could be
 29 calculated based on a mid-year balance. In that case, the mid-year balance in the sinking funds
 30 would be calculated as follows:

and in the Corporation's view more accurate, since it better reflects the interest to be paid in each of the test years.

⁶ Exs. 7 and 4, respectively.

⁷ HC Argument at 3.

⁸ Ex. 7.

$$\text{Mid-Year Sinking Fund Balance} = \text{Opening Sinking Fund Balance in the Year} + \frac{\text{Contributions}}{2}$$

The impact of this adjustment is shown in Table 2 below and is very small (approximately \$6,000 higher sinking fund earnings, which would lower return on ratebase by about \$6,000 in each test year). If directed so by the Board, the Corporation would reflect this adjustment when it files final Phase I schedules.

Table 2. Proposed Calculation of Sinking Fund Earnings (\$000)

	<u>2006/07</u>	<u>2007/08</u>
1 Opening Balance	37,804	43,202
2 add: 1/2 Contributions in the year	1,522	1,522
3 Mid-Year Balance	39,326	44,723
4 Sinking Fund Earnings at 6%	2,360	2,683
5 less: Sinking Fund Management Fees	140	143
6 Sinking Fund Earnings (SFE) for Effective Cost of Longterm Debt	2,220	2,541
7 SFE per October 1, 2007 Schedules	2,214	2,535
8 Difference	6	6

Lastly, as discussed at page 5 of the NTPC Argument, it bears repeating that applying a 6% return to both immunized and non-immunized sinking fund earnings puts pressure on the Corporation to either chase returns beyond the risk-tolerance level it should prudently adopt or accept sinking fund returns below the level incorporated in its rates and not fairly achieving its target return on equity for the test years. Either outcome is inconsistent with the Board's normal approach to regulation.

4. Directive Nos. 10 and 11 – Station Service

The TGC note that based on the Refiling and Refiling IRs that "...it is not possible to verify the accuracy of the 3:2:1 weighting factors prescribed by the Board in Direction 10."⁹ The Corporation will file a table showing the calculation of the weighting factors by community with its final Phase I schedules.

5. Directive No. 12 – Costs and Benefits of AMR Projects

The HC do not dispute the costs and benefits described in the Corporation's response to Directive No. 12. Nonetheless, the HC request the Board to "...direct NTPC to specifically demonstrate the redeployment of linemen budgeted in Fort Smith to all communities in their Phase II filing."¹⁰ The Corporation agrees with that request.

⁹ TGC Argument at 6.

¹⁰ HC Argument at 4.

6. Directive Nos. 15 and 45 – Brushing Expenses

The HC reserve their right to respond to NTPC’s forthcoming review and variance application respecting Directive Nos. 15 and 45.¹¹ The Corporation agrees with that proposition. The HC, however, goes on to suggest that “...the revenue requirements should be reduced at this time to reflect the \$345,000 which was over-collected pending the review and variance application.”¹² The HC’s suggestion is inconsistent with the Board’s findings in Decision 13-2007 and unsupported by regulatory precedent or logic.

Recognizing that Decision 13-2007 may yet be varied, thus far the Board has found that “[a]s there is no evidence to the contrary, the Board accepts NTPC’s argument that the forecast expenditures of \$393,000 for 06/07 and \$401,000 for 07/08 represent the necessary, normalized level of brushing on a go-forward basis” and “...the refunded \$345,000 is to be obtained from NTPC’s non-regulated cash flow, *not by reducing the test year brushing expenditures.*”¹³ Based on those findings, there is no logical basis for disallowing the \$345,000 from the test years’ revenue requirements under a forward test year form of ratemaking. Further, even if Direction No. 15 is upheld, there would be no impact on revenue requirement for the test years once a refund method is determined. Therefore, the Board should deny the HC’s suggestion.

7. Directive No. 18 – Deferral Account Policy

Even though the HC do not suggest that the Corporation’s proposed policy to determine the accounting treatment for deferred costs and deferral accounts is inappropriate or should not be approved, they request that “...each of the deferred costs should be brought forward for review and approval at the next GRA along with a detailed explanation as to why some or all of such costs should not have been included in operating and maintenance expenses in the years incurred.”¹⁴

While the application of the Corporation’s proposed policy may be subject to further review before the Board, the following points should be noted. Deferred treatment of costs incurred over a short period of time for intangible assets that have a long-term or enduring benefit to customers is not new to the Corporation. Such cost treatment has been historically accepted by the Board¹⁵ and has been to the Corporation’s customer’s benefit. Absent deferred cost treatment for such things as debt financing costs, depreciation studies and job evaluation studies, the related costs, if forecast in a GRA test year and consequently built into rates, would be collected at the full amount each year until the next GRA even though the costs are only incurred once.

The TGC appeared to support the Corporation’s position and the use of deferred cost accounting, when it argued in the Phase I proceeding that:

¹¹ HC Argument at 4-5.

¹² HC Argument at 5.

¹³ Decision 13-2007 at 105-06 [emphasis added].

¹⁴ HC Argument at 5.

¹⁵ Refiling, p. 23, lns. 1-5.

1 [i]n our view, the NWT PUB sets the Corporation's Revenue Requirement
 2 considering, amongst other things, *a proper balancing of the interests of*
 3 *customers and the shareholder for example, by approving collection of expenses*
 4 *over a period of years to smooth rates or avoid potential rate spikes.*¹⁶

5 And the Board has found in respect of deferral accounts that “[i]n principle, the Board considers
 6 deferral accounts should be used to record amounts over which the utility has no control or
 7 where the amount cannot be forecast with reasonable accuracy.”¹⁷ The same rationale applies to
 8 the deferred cost treatment proposed by the Corporation in its response to Directive No. 18.

9 **8. Directive No. 19 – Sales Forecasting Methodology**

10 The HC continue to suggest that “...use of the most recent 4-years average use should be utilized
 11 to forecast residential sales in Fort Smith, Fort Resolution, Behchoko and Dettah”, as well as for
 12 general service, presumably in the same communities.¹⁸ The Corporation's position on
 13 substituting the HC's suggested methodology for the applied for GRA sales forecasting
 14 methodology is largely set out at pages 7 to 11 of the NTPC Argument and not repeated in this
 15 Reply Argument. Further, the TGC supports the Corporation's position on this issue.

16 The TGC agree the simple average of 4 years, or the weighted 4-year average
 17 assessment undertaken by NTPC, is *suitable to use as a cross check on the results*
 18 *provided in the Refiling.* However, *given the limited number of years of data and*
 19 *the fact NTPC has not been able to develop a method for normalizing sales to*
 20 *correct for variations in weather, the average use per customer method may not*
 21 *be appropriate for purposes of this GRA.*

22 NTPC should be directed to provide at its next GRA, a proper method which uses
 23 a longer period (at least 10 years of data), for developing a weather normalization
 24 method and determination of average use per customer. As well, NTPC should
 25 also ensure its current method of customer count is also applied to the years prior
 26 to 2002/03 so that there is consistency in the method of developing customer
 27 counts.¹⁹

28 A few remaining points, however, require reply.

29 The HC refer to ATCO Electric's forecast methodology for residential and commercial
 30 customers, among others, as using a regression analysis based on per capita real GDP, HDD, past
 31 energy consumption and time to forecast average use per customer and then multiplies that by
 32 the number of customers.²⁰ While that methodology may be appropriate for a utility of the size,
 33 customer base and service area of ATCO Electric, it is simply not an indication of the
 34 appropriate methodology for the Corporation. For example, the Corporation would have to
 35 determine if information such as per capita real GDP and HDD are even available for each of its

¹⁶ TGC Phase I Argument at 46 [emphasis added].

¹⁷ Decision 9-2006 at 55.

¹⁸ HC Argument at 8.

¹⁹ TGC Argument at 11-12 [emphasis added].

²⁰ HC Argument at 6.

1 communities. Further, while it was noted at page 10 of the NTPC Argument that it would be
2 prudent for the Board to direct the Corporation to examine the average use per customer
3 methodology before specifying a methodology for the next GRA, the Corporation must also
4 consider both the cost and possible benefits of such a study, as such costs will eventually be
5 recovered from its customers.

6 The HC suggest using the 20-year HDD as a proxy for normalized weather.²¹ As previously
7 discussed in the NTPC Argument, the use of HDD as the sole proxy for normalized weather is
8 problematic.²² Further, the 20-year HDD alone does not account for the apparent warming trend
9 that is best represented by a complete and current data set inclusive of 2005/06.²³

10 The HC see “logical reason to weight the average use per customer” but go on to suggest that the
11 4-year weighted average should be rejected because of 2005/06 was milder than the 30 average
12 HDD.²⁴ The HC’s argument demonstrates the need to consider a longer averaging period than
13 just 4 years. It is neither a reasonable nor prudent approach to exclude what the HC alleges to be
14 an anomalous year out of the 4 year sample. Rather, the better approach is to approve the
15 applied for sales forecasts, which have been verified as being reasonable through, among other
16 things, the 4-year weighted average use per customer metric for residential sales, and direct the
17 Corporation to consider the appropriate average use per customer methodology for its next GRA.

18 The HC claims that “...it would be highly inappropriate to judge the methodologies based on the
19 overall impact on revenue requirements.”²⁵ The HC’s claim is not correct and the impact of a
20 sales forecast methodology relative to overall revenue requirement is a meaningful comparison.

21 First, it is important to note that the Corporation strives for forecast accuracy at the community
22 level by making top-down adjustments that are applied to individual communities where
23 regression analysis do not match “...statistics from the GNWT capital spending plans, NWT
24 Housing Corporation plans, and known developments occurring in a community such as
25 construction activity and forecasts provided by other third parties (e.g. NUL, mines, etc)”, as
26 well as current local knowledge provided by the Corporation’s operations and field personnel
27 who live and work in each of the communities.²⁶

28 Second, when applying a different forecast methodology as the HC is doing, some communities
29 will be over and other communities will be under the Corporation’s GRA forecasts – rarely, if
30 ever, will all communities match up perfectly. In that case, it is not appropriate to adjust only
31 those communities which by the HC’s methodology may appear to be under-forecast as
32 compared to the Application without also adjusting communities that appear to be over-forecast.
33 Only increasing certain communities’ sales forecasts upward, as suggested by the HC, would
34 inhibit the Corporation from meeting its corporate-wide revenue requirement. Consequently,

21 HC argument at 7.

22 NTPC Argument at 9, lns. 17-22.

23 See NTPC Argument at 9, lns. 6-16.

24 HC Argument at 7.

25 HC Argument at 7 [emphasis in original].

26 Ex. 7, BR.NTPC-4(d).

1 consideration of a sales forecast methodology relative to overall revenue requirement is indeed
2 meaningful and confirms the validity of the Corporation's GRA sales forecasts.

3 **9. Directive No. 21 – Snare-Yellowknife Water Stabilization Fund**

4 In Directive No. 21, the Board requested a proposal to exclude the costs and risks associated with
5 generation and transmission outages from the Water Stab Fund, having regard to the
6 administrative costs involved. The Corporation's response incorporated forced outage rates
7 previously approved by the Board as a simple method within the time available before the
8 Refiling. The HC repeatedly cautions against the Board approving the simplest method based on
9 the RFC approved force outage rates without further examination of the individual hydro unit
10 outage calculations, among other things. The Corporation agrees that further examination before
11 any adjustments are made to the Water Stab Fund would be prudent and also noted its many
12 concerns regarding implementation of the requested proposal.²⁷ The Corporation also agrees
13 with the HC's suggestion to defer final resolution of the Water Stab Fund until the next GRA.

14 As a result, the Corporation would make the following revisions to its Refiling revenue
15 requirements:

- 16 • reduce the Snare/Yellowknife Diesel Generation Forecast to 2.109 GW.h in
17 2006/07 and 1.379 GW.h in 2007/08, consistent with the May 16, 2007 version of
18 the Phase I schedules;
- 19 • remove fuel expense related to this generation from the revenue requirement as it
20 will be captured by the Water Stab Fund, as has been shown previously in
21 Schedule 3.1; and
- 22 • remove the impact of capitalizing fuel expense from capital projects in the test
23 years (resulting in slightly lower capital additions and ratebase).

24 It should be noted that since no water stabilization fund was approved for the Taltson system, the
25 Corporation would continue to reflect fuel expense on the Taltson system in its revenue
26 requirement.

27 **10. Directive No. 22 – Diesel Fuel Stabilization Fund**

28 The Corporation notes that it inadvertently missed including reference to Directive No. 22 in its
29 Refiling Argument. The intended references would have been to include Directive No. 22 in
30 both the requested relief in section 2(i) and the matrix in section 3. Consequently, the
31 Corporation respectfully submits that the Board should also declare that NTPC has fully
32 complied with Directive No. 22. The Corporation apologizes for any inconvenience that may
33 have caused the Board or parties.

34 The TGC correctly notes that the Corporation's "...indexing proposal does not take into account
35 the differential costs related to fuel delivery" and alleges that the Board intended such cost

²⁷ NTPC Argument at 12-14.

1 differentials be accounted for. The TGC suggests that a community specific
2 transportation/delivery cost rider be added to the Corporation's indexed proposal.²⁸

3 In considering the TGC's request, it is important to recall two aspects of the Corporation's fuel
4 supply arrangement with the Petroleum Products Division ("PPD"). First, the PPD provided the
5 Corporation with price estimates for the test years that included a commodity price, a delivery
6 charge and fuel taxes.²⁹ Therefore, price differentials between communities based on differing
7 transportation costs have already been considered in the test year fuel price forecasts. Given that
8 PPD already supplies fuel to all of these communities and has contracts in place with
9 transportation service providers, the TGC's scenario that considers the effects of transportation
10 costs dramatically increasing for only one community, while all others remain unchanged, is
11 purely hypothetical. The chances of that situation emerging in practice is very unlikely.

12 Second, fuel procurement in the test years that will be provided by the PPD includes
13 transportation and storage. The Corporation purchases fuel at the point of consumption and pays
14 one price for the fuel.³⁰ The Corporation does not pay separate commodity and transportation
15 prices. It would be very difficult, if not impossible, in practice to separate out the transportation
16 portion of the fuel price from the commodity portion and fuel taxes.

17 The TGC's request indirectly seeks community specific stabilization funds. While the Board
18 found that the fuel riders should follow the community costs as closely as possible, it clearly did
19 not go so far as to require the Corporation track 100% of fuel costs for each community, which
20 would amount to NTPC implementing community specific fuel stabilization funds. Given that
21 the Corporation purchases its fuel for those communities from one supplier, the chance that
22 transportation costs would increase dramatically for only one community is unlikely. What is
23 certain, however, is that the requirement to unbundle transportation costs from other elements of
24 the fuel cost and track those costs separately on a community-by-community basis would amount
25 to a considerable extra administrative cost to the Corporation and customers, with limited, if any,
26 added cost tracking benefits. Therefore the TGC's suggestion should be denied.

27 **11. Directive No. 51 – Generation Using Sources Other than Diesel**

28 The TGC have identified a number of items which they would like to see the Corporation report
29 on in its response to Directive No. 51 and suggest that the Board should direct NTPC to include
30 those items in its reports.³¹

31 It is simply premature at this time to judge the completeness of the Corporation's response to
32 Directive No. 51, which has not yet been considered and assessed by the Corporation, much less
33 drafted. The Board made its expectations sufficiently clear in Decision 13-2007. The TGC has
34 also made its expectations clear. The Corporation will consider both sets of expectations in
35 preparation of its response to Directive No. 51 having regard to the corresponding costs of

²⁸ TGC Argument at 7-8.

²⁹ Ex. 7, TGC.NTPC-40.

³⁰ Ex. 7, BR.NTPC-7. Also, Aklavik is not included in the PPD Agreement due to the fact that NTPC does not have fuel storage facilities in that community. However, fuel storage facilities in Aklavik will be constructed as part of the new power plant and it is expected that Aklavik will be included in the PPD Agreement at that time.

³¹ TGC Argument at 5.

